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9 Research Gap Analysis

9.1 Scope Statement

"Determine SCC related R&D issues that warrant further research."

The purposes of this section are to 1) identify gaps in the current understanding of SCC of pipelines and ways to manage the problem, 2) identify R&D that could be conducted to fill those gaps, and 3) prioritize the R&D topics based upon qualitative cost/benefit considerations. This section addresses the complete spectrum of R&D from basic research to understand the mechanisms of SCC in line pipe steels through applied research to understand the causes of SCC in pipelines to very applied R&D directed toward developing ways to manage the problem in the field. For each of those areas of research, this section summarizes the results of prior research, identifies remaining gaps, and discusses future R&D directions.

Four factors are considered in terms of the potential benefits of each R&D topic:

- **Safety** of the pipeline system clearly is the most important factor, so the relevance of the R&D to reducing the number of service failures is the first criterion.
- The potential impact on **cost reduction** is important to the pipeline industry and to the general public, because the costs of failures and the costs of prevention or mitigation eventually affect the cost of the product.
- The **size of the knowledge gap** also should be considered. If the level of understanding is relatively high, additional R&D may have a comparatively small effect on decisions regarding safety and cost.
- The **probability of success** in terms of a viable R&D approach that has a good potential for answering the remaining questions also should be considered.

It is not possible to quantify the above benefits, but considering them, with more emphasis on the first two, will allow various R&D topics to be ranked relative to each other in terms of potential benefits.

Quantification of the costs of required future R&D also is not possible without specific knowledge of the approaches that might be proposed by organizations that will conduct the R&D. However, based upon experience conducting R&D on SCC, judgments about the order of magnitude of probable R&D costs have been made.

9.2 SCC R&D Needs Discussion

Appendix A contains discussion of the history of R&D relating to both high pH and near-neutral pH SCC in several areas:

- Mechanisms of SCC
- Causes of SCC

- Methods for Managing SCC
    - Site-Selection Models
    - Crack-Growth Models
    - ILI Technologies
    - In-the-Ditch Sizing
    - Effect of Temperature
    - Steel Susceptibility

Each discussion area presents a summary of the background of R&D in the area, along with a discussion of gaps in the effort in each area. Generally, the discussion is targeted at making distinctions based on the four factors presented in Section 9.1 for each R&D area.

9.3 Prioritization of R&D Gaps

9.3.1 Criteria for Prioritizing

The research approaches to address the various knowledge gaps identified in Appendix A can be grouped into the following eight topics:

1. Develop improved site-selection models. In addition to research directed specifically at model development, this topic also would include basic research into the role of hydrogen in near neutral-pH SCC and the field environments that cause near neutral-pH SCC, because both of those subjects are related to identifying probable locations of SCC. This topic also is directly related to SCC Direct Assessment.
2. Develop improved crack-growth models. This topic would include research into the effect of stress fluctuations on crack growth and should deal with both high-pH SCC and near neutral-pH SCC.
3. Develop or identify new approaches or technologies for ILI, particularly for gas pipelines. This would involve a search for technologies other than the traditional approaches that rely upon magnetic-flux leakage or ultrasonics.
4. Develop new tools based upon emerging technologies such as EMAT.
5. Develop improved methods for sizing cracks in the ditch.
6. Determine the effects, if any, of temperature on near neutral-pH SCC.
7. Correlate SCC susceptibility with the composition and microstructure of steels.
8. Develop a fundamental understanding of the relationship between SCC susceptibility and the composition, processing, microstructure, and mechanical properties of steels.

The following section discusses the benefits of conducting more research into each of those topics in terms of the potential impact on safety, the potential for reducing cost, the size of the knowledge gap, and the probability that the research will be successful.

9.3.2 Benefit Analysis

Site-Selection Models. The ability to predict where SCC is likely to occur would be valuable in terms of safety because it would allow pipeline operators to focus their attention on areas of highest risk and to prioritize their actions. The ability to predict where SCC is not possible would be very important in terms of cost reduction because it could eliminate wasted costs of dealing with portions of the pipeline that are not susceptible to SCC.

Because of the many factors that affect the probability of SCC and the difficulty of measuring some of them, SCC detection and mitigation is challenging for operators. For example, soil chemistries and geological conditions are extremely complex, the condition of the coating may be unknown, the susceptibility of the steel probably will be unknown, and the history and relevance of prior operating conditions such as pressure fluctuations and cathodic protection levels may be difficult to interpret. Thus, the probability of developing a comprehensive, highly accurate predictive model may not be high, but even limited success could be very useful, especially with respect to direct assessment.

Crack-Growth Models. Once stress corrosion cracks are discovered in a pipeline, it would be very beneficial from a safety standpoint to be able to predict how long those cracks could be left in the line, either under normal operating conditions or modified operating conditions. The ability to relate crack growth to operating conditions also would be very important for direct assessment, as operating history would be one of the factors to consider in evaluating the probability of SCC in an area of interest. Improved crack-growth models also could have a large impact on cost reduction because they would be the basis for calculating optimum intervals between hydrostatic tests or ILI runs, and for areas where the maximum crack growth rate could be shown to be very low, the need for any remedial measures might be eliminated. Although simplified crack-growth models currently exist and are useful, significant technical challenges remain for making the models more accurate, especially involving issues such as the relationship of crack growth to pressure fluctuations, time-dependent changes in the creep resistance of the steel, and predicting the environmental conditions at the surface of the pipe. Nevertheless, reasonable approaches to those issues have been suggested and further improvements in the models, therefore, can be expected.

New ILI Technologies. Probably the ideal way to manage SCC would be to use a low-cost ILI technology that could locate cracks, differentiate them from other anomalies, and provide an accurate description of their sizes.

Unfortunately, current commercial tools are very expensive to run, and the most reliable ones are only applicable to liquid-filled pipelines. Therefore, there is a strong desire from both safety and cost perspectives to find a new, lower cost alternative, especially for gas pipelines. There is a significant challenge to conceive an approach that has not already been pursued by the ILI industry. However, several new concepts currently are being investigated, and other ideas should be encouraged and explored.

Develop and Evaluate Tools for Emerging ILI Technologies. An ILI tool for a pipeline must be extremely sensitive in order to detect the very small defects of interest and, at the same time, be very rugged to survive the journey through the pipeline. Therefore, the development of a tool can require tens of millions of dollars. New tools based upon technologies such as EMAT and circumferential magnetic flux leakage (MFL) are appearing on the market, but their reliability and accuracy have not been confirmed. If successful, these technologies could have a major impact on safety, but will be very expensive for operators to purchase and maintain.

In-the-Ditch Measurements. From a safety standpoint, it should not be necessary to remove very small stress corrosion cracks from a pipeline, especially since many most likely are dormant, and it certainly would not be economical to do so. Although current technologies are not completely accurate and are somewhat cumbersome, improvements are forthcoming.

Temperature Effects. Temperature effects on high-pH SCC are well enough understood that further R&D probably would not improve safety or reduce costs. While temperature effects on near neutral-pH SCC are less well established, field experience by the industry would suggest that temperature probably is not a significant factor for that form of SCC.

Correlate Steel Susceptibility with Composition and Microstructure. Although it would be highly desirable to build future pipelines from steels resistant to SCC regardless of the environment or stress, the challenges to designing such steels are significant, and other approaches such as improved coatings and surface treatments (shot peening or grit blasting) are relatively low-cost alternatives.

Develop Fundamental Understanding of Relationship Between Steel Susceptibility and Composition, Processing, Microstructure, and Mechanical Properties. A fundamental understanding of the factors that affect steel susceptibility would provide a much better basis for designing a resistant steel than would an empirical correlation, but it also would be much more expensive to develop.

The potential benefits related to each of the suggested research areas are summarized in Table 9.1.

9.3.3 Cost Analysis

The probable costs to complete each of the research areas mentioned above have been estimated based upon experience with similar previous research efforts. Because precise cost estimates would depend upon the specific approaches chosen for each area and the organization that would conduct the research, only order-of-magnitude estimates are possible at this time. The estimated costs are summarized in Table 9.2, where the following definitions apply:

Very High: Greater than 10 million dollars

High: Several hundred thousand to 2 million dollars

Medium: 1 hundred thousand to several hundred thousand dollars

Low: 50 to 100 thousand dollars

Table 9.1 Qualitative Rating of Potential Benefits from Various Research Areas

Research Area	Magnitude of Benefit			
	Safety	Cost Reduction	Size of Gap	Probability of Success
Site-Selection Models	High	Very High	High	Medium
Crack-Growth Models	Very High	Very High	High	High
ILI – New Technology	Very High	Very High	Very High	Medium
ILI – Develop Tool	Very High	Medium	Medium	High
In-the-Ditch Measurement	High	Medium	Medium	High
Temperature Effects	Low	Low	Low	High
Steel – Empirical Approach	Medium	Low	Very High	Medium
Steel – Fundamental Approach	Medium	Low	Very High	High

Table 9.2 Qualitative Rating of Costs to Complete Various Research Areas

Research Area	Cost
Site-Selection Models	High
Crack-Growth Models	High
ILI – New Technology	Medium
ILI – Develop Tool	Very High
In-the-Ditch Measurement	Medium
Temperature Effects	Low
Steel – Empirical Approach	Medium
Steel – Fundamental Approach	High

9.3.4 Summary of R&D Priorities

Based upon the benefit and cost analysis described above, each of the suggested research areas has been represented in Figure 9-1 in terms of a qualitative cost/benefit ranking. By necessity, the axes do not contain numerical values, and the positioning of each point is highly judgmental. It would be appropriate to think of the axes as logarithmic scales.

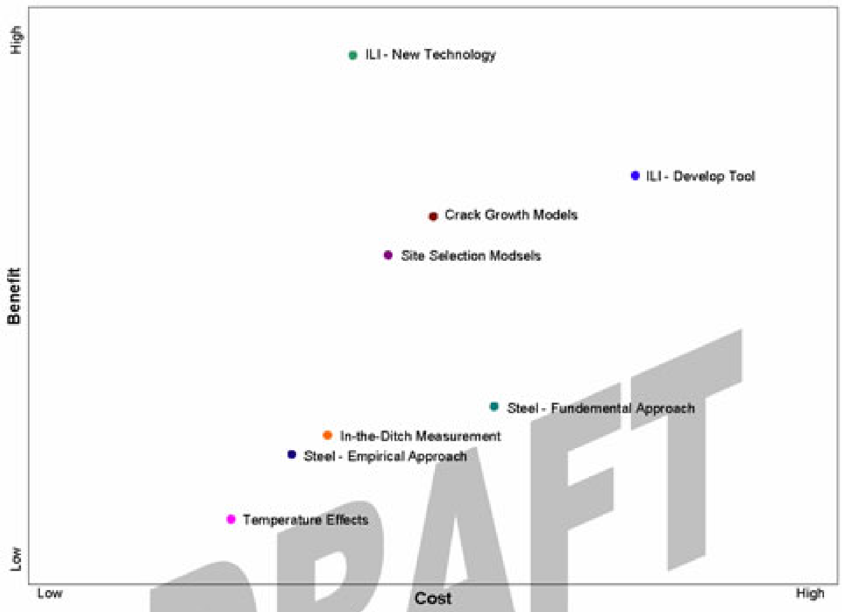

Figure 9-1 Qualitative Ranking of Research Areas by Cost/Benefit Ratio

9.4 References

(References to the R&D areas are contained at the end of Appendix A).

10 Industry Practice Regarding SCC

10.1 Scope Statement

"Develop a practicable procedure regarding how to assess SCC in operating pipelines within the context of integrity management."

This work item is addressed first in Chapter 10 and concluded in Chapter 11. This first chapter addresses both the capabilities of current practice and through an operator survey and operator interviews, the current methods of implementation by the industry. Chapter 11 addresses the same issues, but from the viewpoint of how these practices fit within and address the regulatory requirements of an Integrity Management (IM) program.

10.2 Questionnaire Concerning Current Assessment Procedures

In order to understand and assess the practices employed by operators to address SCC, Baker prepared a survey document to assist in gathering information from pipeline operators on SCC occurrence history and operating company practices for SCC detection, management and mitigation. The survey was drafted by Baker and reviewed by a working committee of INGAA, headed by Dave Johnson of Cross Country Energy Services, LLC, which made suggestions for improvement. The comments aided in streamlining the survey in order to provide for the rapid gathering of relevant information. The survey and cover letter were sent to member companies by the trade associations themselves. A copy of the survey and cover letter is included as Attachment A.

In endorsing the completion of the survey, INGAA and API, in their cover memo to member companies, stressed the importance of industry input into the process. The American Gas Association (AGA) also distributed the survey to their member companies who operate a reasonable amount of transmission pipe that could be affected by SCC.

Forty-two survey forms were returned, with one additional response made via email only. These responses represent 34 distinct operating entities, representing 45 natural gas and liquid pipelines. Note that one form addressed multiple pipeline systems, while other forms covering separate pipelines were reported by the same person or group. Also, note that not all respondents answered every survey question. Because the trade associations distributed the survey forms, the percentage of respondents from the original distribution cannot be determined. In general, however, the level of response was considered good, and appreciation is given to INGAA, API and AGA for their support.

10.3 Summary of Questionnaire Responses

10.3.1 SCC Occurrence Information

Twenty-three of the responses indicated that SCC had been detected, with the earliest detection noted as 1965. The system age at the time of first detection ranges from 7 years to 70 years, with an average of 29 years. It is important to note that, typical of such responses with a relatively small data base, numerical averages are skewed by disproportionate numbers that may be attributed to a relatively small number of pipeline systems. For example, one operator reported 46 SCC in-service failures. Five other operators reported over 30 hydrostatic test failures apiece, with the highest reported by two operators being, coincidentally, 61. Thus, the numerical average numbers developed from this operator survey, such as of SCC in-service and hydrostatic failures (six and fifteen, respectively) can be misleading, and should not be construed as representative of industry averages.

Based on the responses received, the number of main line valve sections where SCC has been detected ranged from 48 percent down to 0.1 percent of the total number of mainline valve sections comprising each pipeline system. Approximately 45 percent of the SCC occurrences found were during inspections specifically for SCC, another 35 percent of the SCC occurrences were noted as found during an inspection specifically for SCC or during an inspection for other reasons, while the remaining 20 percent were found during an inspection not specifically looking for SCC.

Of the pipelines where SCC was noted by the respondents as having been detected (23 pipelines), 65 percent (fifteen pipelines) are natural gas lines and 35 percent (eight pipelines) are liquids lines. Since mitigation, 20 pipelines of these pipeline segments were reported as not having experienced additional in-service or hydrostatic test failures.

10.3.2 SCC Detection Methods

There are several nondestructive examination (NDE) methods available for identifying SCC on a pipeline system. The most common include:

- Visual – The pipe is exposed and the pipe coating is examined for soundness and performance. The coating is then removed at locations where disbonding is suspected and a technician examines the pipe surface for evidence of cracking. Note that normally SCC colonies cannot be detected by the naked eye.
- Magnetic Particle – The pipe is examined visually with the assistance of magnetic particle imaging.
- Liquid Dye Penetrant – The use of dyes on the surface of the pipe to enhance the visualization of cracks.
- Eddy Current – The use of eddy currents to measure the occurrences of cracking.
- ILI Tool – MFL, TFI, EMAT, etc.

On the survey form, the respondents could make multiple selections as to the methods employed. The percentages of distinct operator entities utilizing each of the NDE methods for SCC detection described above are summarized in Table 10.1.

Table 10.1 NDE Methods Used for SCC Detection

NDE Method	Number of Operators	Percent of Operators
Visual	21 (of 34 operators)	62%
Magnetic Particle	18	53%
Liquid Dye Penetrant	5	15%
Eddy Current	1	3%
ILI	10	29%
Other	5	15%

For the "other" category, operators comments included: Destructive laboratory methods, metallurgical examination and optical microscopy; 100 mV Shift Close Interval Survey, DCVG; field ultrasonic techniques; and, metallography.

Of the operators that responded as to whether or not they had written procedures for NDE evaluation, physical field practices for SCC detection, and/or reassessment intervals if SCC is detected, 81 percent (26 of 32), 73 percent (24 of 33) and 50 percent (16 of 32) responded "yes," respectively.

10.3.3 SCC Management

There are a number of management practices available for SCC. The following is a list of management practices specifically noted on the survey form:

- Failure History Characterization – Use information of past SCC failures as an indication of the specific conditions that may result in the future occurrence of SCC.
- Coating Type Characterization (Coal Tar, Tape, etc.) – Characterizes the condition and type of coating, and correlates the information with the occurrence of SCC.
- Pipe Material Characterization (API Grades, Pipe Mill, etc.) – Characterizes the type of pipe and correlates it to the occurrence of SCC.
- Operation Characterization (Pressure, Temperature, etc.) – Correlates the specific operating conditions of the pipeline with the occurrence of SCC.
- Location Characterization – Correlates the environmental conditions near the pipe with the occurrence of SCC.
- Age Characterization – Correlates the age of the facilities with the occurrence of SCC.
- Bell Hole Characterization – Results of buried pipe inspection reports are utilized to determine if there are common characteristics in pipe with SCC compared to pipe with no SCC utilizing trending analysis.
- Magnetic Flux Leakage ILI Characterization – Utilization of MFL ILI tools to detect SCC.
- Other ILI Characterization – Utilization of other ILI tools to detect SCC.

- Cathodic Protection Level Characterization (Voltage Levels) – Monitoring of CP voltage levels at locations with and without active SCC for use as a predictive tool.
- Hydrostatic Retest Program – Testing pipe to determine presence of SCC. If test pressure critical size cracks are present, a rupture of the line will likely occur.
- External Corrosion Direct Assessment
- Risk Assessment Ranking (Segment by Segment Comparison)

On the survey form, the respondents could make multiple selections as to the methods employed. The percentages of distinct operator entities utilizing each of the SCC management practices described above are summarized in Table 10.2.

Table 10.2 SCC Management Practices

SCC Management	Number of Operators	Percent of Operators
Failure History Characterization	20 (of 34 operators)	59%
Coating Type Characterization	20	59%
Pipe Material Characterization	9	26%
Operation Characterization	21	62%
Location Characterization	13	38%
Age Characterization	15	44%
Bell Hole Characterization	13	38%
Magnetic Flux Leakage ILI Characterization	13	38%
Other ILI Characterization	8	24%
Cathodic Protection Level Characterization	13	38%
Hydrostatic Retest Program	14	41%
External Corrosion Direct Assessment	9	26%
Risk Assessment Ranking	13	38%

Approximately 48 percent (16) of the operators who responded when asked whether or not they had written procedures for SCC management (33) answered "yes." Of the 14 distinct operators who indicated how long these written procedures had been in place, four stated that they have had a written procedure for 30 or more years on at least one of their pipeline systems. Six operators indicated implementation of written procedures within only the last four years on at least one of their pipeline systems.

10.3.4 SCC Mitigation

SCC mitigation techniques identified in the survey include:

- Operating Condition Modification (Pressure or Temperature Reductions, etc.)
- Selective Sleeve Installation
- Clean Pipe and Recoat
- Grind Pipe and Recoat

- Soil Condition Modification (Drainage Pattern Change, Replacement or Chemical Treatment of Soil, etc.)

On the survey form, the respondents could make multiple selections as to the techniques employed. The percentages of distinct operator entities utilizing each of the SCC mitigation techniques described above are summarized in Table 10.3.

Table 10.3 SCC Mitigation Techniques

SCC Mitigation	Number of Operators	Percent of Operators
Operating Condition Modification	17 (of 34 operators)	50%
Selective Sleeve Installation	17	50%
Clean Pipe and Recoat	12	35%
Grind Pipe and Recoat	15	44%
Soil Condition Modification	2	6%
Other	15	44%

Of the 31 operators that responded as to whether or not they had written procedures for SCC mitigation, approximately 52 percent (16 operators) responded "yes."

10.4 Operator Interviews

A series of operator interviews were conducted subsequent to receipt of the responses to the questionnaire. The operators were very cooperative in supplying information regarding their procedures and policies. Results from the interviews are summarized in Table 10.4 with additional details in the following sections.

Table 10.4 Summary of Operator Interviews

	Operator						
	A	B	C	D	E	F	G
Operates hazardous liquid (L) or gas (G) transmission pipelines.	G	G	L	G	G	G	L
Has operator experienced in-service failures (leaks or ruptures) attributed to SCC? Yes (Y) or No (N)	Y	Y	N	N	Y	Y	Y
Has operator experienced hydrostatic testing failures (leaks or ruptures) attributed to SCC? Yes (Y) or No (N)	Y	Y	N	Y	Y	Y	Y
Has operator discovered SCC using ILI (I) or MPI (M)?	I/M	I/M	I/M	M	I/M	M	
Has operator attributed observed SCC to high-pH SCC? Primarily (P), Mixed (M), None (N)	P	M		P		P	P
Has operator attributed observed SCC to near-neutral pH SCC? Primarily (P), Mixed (M), None (N)		P	P	N	P	N	N
Does operator consider ILI reliable for detection of SCC? Yes (Y) or No (N)	N	N	Y	N	N	N	
Does operator rely primarily upon hydrostatic testing for detection of SCC? Yes (Y) or No (N)		N	N	Y	Y	Y	Y

10.4.1 Operator A

Operator A operates several major gas pipelines. A southern pipeline had 14 in service failures. All of these were at tape coating sections. Since they instituted a spike test, followed by normal hydrotest, they have experienced no further in-service failures in this line, although there have been some test failures. They established their re-inspection interval based on an early Life Prediction Model developed by Brian Leis/PRCI. Currently they are using a 7-year re-test interval.

One of their northern lines had instances of SCC detected by inspection of sites selected as potentially favorable for occurrence of SCC, based upon the experiences of TCPL. Crack depth in all instances was less than 10 percent of the wall, and the repair procedure was to grind out the SCC indications.

Generally, fusion-bonded epoxy (FBE) external coating has performed well and Operator A concludes that FBE should be viewed as a mature coating that consistently performs well given good application procedure. They specify 14-16 mils thickness for FBE.

Operator A has issued an internal safety advisory bulletin on SCC while a procedure for inspection of pipe under disbonded coating for SCC is being developed. Operator A performs wet fluorescent magnetic particle inspection (WFMT) whenever there is evidence of a disbonded coating. They are currently training in-house corrosion technicians/engineers to the latest draft of their SCC procedure and expect to adopt it as an operating procedure once their in-house resources are fully trained to the procedure. The instances and evaluation of these excavations will be added to their in-house database.

The idea of operators sharing their individual databases relating to occurrence of SCC with the pipeline industry was discussed. Operator A believes an industry-wide SCC database might be helpful, and would consider participation if individual corporate names associated with the data need not be attributed within the database. An industry organization such as PRCI might be a good "clearinghouse" for an SCC database.

Concerning ILI, Operator A has concluded that the ILI industry does not offer an effective tool for detecting SCC in gas pipelines. Operator A tried and abandoned use of the liquid coupled elastic wave tool, and mentioned that running tools in slugs is expensive and disruptive to operations, requiring drying the line in addition to the other considerations. The possibilities of EMAT were discussed, though no specifics were available.

Operator A recognizes that initiation of SCC, as well as reactivation of dormant SCC, is related to strain rates imposed by pressure cycles being within a critical range; however, they note that control of pressure cycles to avoid the critical range of strain rate is not feasible.

To summarize, Operator A asked that SCC be characterized in perspective to a number of operational considerations, including not only other more frequent failure modes, but also concerns over supply reliability. Pipelines that cannot be pigged must be shut down in order to perform an integrity assessment using hydrostatic testing. Interrupting operation of a single pipeline that supplies power plants or local distribution companies (LDC) may have significant economic impact upon a community and result in other public concerns and safety issues. Direct assessment for identification of SCC has not proven sufficiently reliable to substitute for hydrostatic testing.

Operator A identified a need for collaborative funding for improvement in ILI tools for detection of SCC, and for development and validation of direct assessment methods for SCC.

10.4.2 Operator B

Discussion with Operator B was limited to their interstate gas pipelines. The original pipeline was constructed in 1931 and was assembled by oxy-fuel welding and couplings, and has since been phased out of operation. The remaining looped pipeline segments date from the 1940s to 1970s and is predominately Nominal Pipe Size (NPS) 30 and 36.

This portion of Operator B's system experienced two in-service failures identified as classic or high-pH SCC in 1973 and 1984. These two failures were classic in that they were located in the first valve section downstream from a compressor station. After these two SCC failures, Operator B initiated a program of hydrostatic testing for the first valve sections downstream from compressor stations. Initially these hydrostatic tests were at 105 percent of SMYS at the lowest elevation for 1 hour, but were later revised to spike-type tests at 100 to 110 percent of SMYS for 1 hour followed by 100 percent of SMYS for 7 hours.

Operator B has not experienced hydrostatic test failures attributed to classic SCC, nor have they identified other classic SCC incidents as a result of inspection of exposed pipe.

Operator B has experienced multiple in-service failures attributed to low- or near neutral-pH SCC on NPS 26, 30 and 36 pipeline segments coated with asphalt enamel external coating. Subsequent hydrostatic testing and direct examination has revealed other instances of near neutral- pH SCC associated with disbonded asphalt enamel coating.

Operator B has observed the following characteristics of near neutral-pH SCC on their large-diameter system:

- Asphalt enamel coating that has disbonded, typically around the full circumference of the pipe, and for a significant distance along the length of the pipe, but remains intact as a shell around the pipe.
- A film of water between the disbonded external coating and the pipe surface.
- Adherent surface deposits containing:
  - rust-colored iron oxide,
  - powdery white calcium carbonate, and
  - pasty white iron carbonate.
- Shallow pitting corrosion.
- Families or colonies of parallel cracks aligned with the axis of the pipe (circumferential SCC has not been observed). Most cracks are relatively shallow, but linked cracks have been sufficiently deep to cause the in-service failures at normal operating pressures.

Operator B has prepared an SCC Comparator that is distributed to field personnel who may be present at excavation sites and have occasion to observe and report on the condition of the pipeline. The SCC Comparator is a laminated sheet printed front and back that includes color photographs of known instances of SCC that field personnel can reference during direct examination of excavated pipe. Field personnel who observe the characteristics in the above bullet list are instructed to request that a corrosion specialist inspect the pipe further for SCC.

After the second in-service failure attributed to near neutral-pH SCC, Operator B contracted with GE-PII to perform an ILI with their Elastic Wave Tool on the pipeline that experienced the failure. Subsequent direct examination revealed that while the Elastic Wave Tool can detect SCC, other surface conditions that are not injurious to integrity are also reported. The number of indications that are not SCC may exceed the number of SCC indications by three to ten.

Operator B has invested considerable effort to identify other information that can be integrated with the results from the Elastic Wave Tool to increase the probability of identifying near neutral-pH SCC at a dig site. Operator B reports that integration of results from:

- a high-resolution MFL tool, graded for external corrosion depths up to 10 percent pipe body wall penetration,
- the Marr Associates Soil Characterization/SCC predictive model, and
- close-interval CP survey,

combined with the results from the Elastic Wave Tool significantly increases the probability of correctly predicting the location of near neutral-pH SCC on their system.

The MFL tool results are graded to identify indications of pitting corrosion with up to 10 percent wall loss (different from grading for identification of significant wall loss) but with no deeper corrosion. Locations with relatively minor pitting corrosion are likely to be associated with disbonded, but intact external coating with corrosive water between the coating and pipe surface.

The Marr Soil Model identifies locations where near neutral pH SCC may occur if disbonded coating is present.

Acceptable results from close interval surveys are consistent with absence of extensive coating holidays, or disbonded coating that remains intact.

By application of all of the criteria, Operator B identifies locations with otherwise minor pitting corrosion that could occur under disbonded coating, soil conditions that may cause SCC and indications of surface conditions that may be SCC.

During excavation and direct examination of locations selected by the screening method, the pipe is evaluated by visual examination for deposits. The pipe surface is cleaned with a brush-off blast and examined for shallow pitting corrosion and with MPI, typically using the wet black powder on white background.

Operator B employs manual UT to evaluate depth of near neutral-pH SCC revealed by MPI.

Depending upon depth of identified SCC, Operator B may grind the cracks to sound metal and recoat, or replace the section with new pipe.

Operator B reports application of epoxy coating to all large diameter pipe exposed for direct examination and considers that to be a permanent solution to avoiding SCC at the recoated locations, even if minor surface cracks remain.

Operator B hydrostatically tests each valve section where near neutral pH SCC has been identified, examined and repaired. Operator B acknowledges that shallow near neutral pH SCC under disbonded coating that was not removed for direct examination may survive hydrostatic testing and may eventually grow deeper.

Operator B has a 3-year contact with GE-PII for ILI services and works closely with GE-PII to improve reliability of their tools for detection of SCC in gas transmission pipelines. Operator B has previously been an active member of the AGA-Pipeline Research Committee (now Pipeline Research Council International, Inc.) for decades and favors cooperative funding of the improvement of ILI technology for detection of SCC.

10.4.3 Operator C

Operator C operates thousands of miles of large diameter transmission and distribution lines through out Canada and the US. These lines range in diameter from 10-inch to 48-inch NPS. The system transports liquids with roughly 50 different commodities from jet fuel to crude oil. Another group operates the gas transportation side of their business.

The dates of construction for the system range from the 1940s to the present. The coating type varies with somewhere between 30 and 40 percent being polyethylene tape wrap. The current coating of choice for new construction is fusion-bonded epoxy, though the use of a three-part powder polyethylene coating was mentioned. Nearly all of their system is designed to allow passage of ILI tools.

Operator C employs approximately 30 people within their integrity management group. The overall program is driven by the company's main goal of NO leaks.

They approach SCC as just one portion of an overall defect management program, which attempts to prevent the occurrence of defects, locate defects that do occur and mitigate defects as appropriate. They use ILI as the primary source of data gathering. In particular, the use of high-resolution UT tools has been used effectively for detection of SCC. While they rely upon the ILI tool vendors for initial data processing, they apply in-house knowledge to validate and improve ILI data interpretation. This has resulted in reducing the number of false positive anomaly reports. They anticipate conducting nearly 6,000 miles of ILI this year.

They do not utilize a specific hydrostatic testing program for defect management as they feel that ILI is more accurate and cost effective.

Operator C performs approximately 1,000 digs per year based on ILI results. Whenever the pipe is exposed, magnetic particle inspection (black on white) and ultrasonic testing (shear wave) is conducted. The lack of a specific ASNT training manifest for pipeline inspectors was mentioned as an area of potential improvement.

They currently base SCC fitness-for-service (FFS) analysis on the AGA NG-18 ln-secant formula for critical flaw size, though they noted that this is not entirely appropriate since this formula is for analysis of a semi-elliptical flaw, which is somewhat different than what occurs within an SCC colony. They have been conducting burst tests on cut-out sections of pipe containing SCC with results being collected in an empirical database, which can then be used to refine the FFS analysis.

Operator C feels that the pressure cycle/profile or, in actuality, the strain rate associated with pressure fluctuations has a direct effect on the growth and dormancy of SCC. High strain rates equates to high occurrences of SCC.

The majority of SCC found has been the near neutral-pH type, which is consistent with the general findings that near neutral-pH SCC occurs more on pipelines that experience low soil temperatures. It was postulated that related to the higher solubility of CO_2 at lower temperatures.

If SCC is found, the cracks are ground out if possible with pressure capacity checks being made using RSTENG. If necessary, full encirclement, pressure-containing sleeves are installed over the area, or if SCC is present over a large area, an entire section may be replaced. In any case, the repaired section is recoated with the recoating extending virtually the entire length of the excavation.

While Operator C has not had any failures related to SCC (they have experienced corrosion fatigue incidents), they indicated that post-incident response would initially be the same as any incident. They have procedures in place on accident investigation including transportation of failed sections and laboratory examination. If the forensic investigation concludes that the cause was SCC, then their integrity management program is used to determine an appropriate long-term response. In the opinion of Operator C, a pressure reduction to 80 percent of the level at which the failure occurred, which is widely applied when responding to an SCC incident, is effective approximately 80 percent of the time; however, additional site-specific analysis is needed to determine the final long-term response.

Operator C cooperates with and supports both PRCI and CEPA in basic research, but also performs substantial in-house research on ILI, repair techniques and non-destructive evaluation.

10.4.4 Operator D

Operator D operates multiple pipeline systems that include thousands of miles of pipeline transporting gas from the Gulf Coast to the Northeast USA. One of these systems is nearly 100 percent piggable and has been entirely pigged. Another of the systems is approximately 75 percent piggable, and all of the piggable sections have been pigged. The systems include approximately 170 valve sections that are immediately downstream from compressor stations.

The Integrity Management Program for Operator D is organized under a Director of Pipeline Integrity & Operational Compliance who reports to the Vice President of Operations. Responsibility for mitigation of stress-corrosion cracking (SCC) is assigned across three groups headed by Managers reporting to the Director.

- Manager - Operational Compliance
- Manager - Pipeline Integrity
- Manager - Metallurgical Services

Operator D was proactive in initiating a hydrostatic testing program of the first valve sections downstream from compressor stations in 1986 without suffering an in-service failure. To date, Operator D has tested 63 valve sections containing approximately 1,343 miles of pipeline. Operator D employs a spike hydrostatic test program with the test pressure for the first hour producing a hoop stress greater than 100 percent of SMYS, and the remaining seven hours at a test pressure producing a stress greater than 90 percent to SMYS. Operator D routinely employs a flame-ionization leak survey immediately after return-to-service from hydrostatic testing, followed by one or two subsequent leak surveys after two or three month intervals. Operator D considers the post-test flame-ionization leak surveys technically superior for detection of small leaks compared to the seven-hour hold period of hydrostatic testing.

Operator D has experienced approximately 12 pipeline failures (leaks and ruptures) during hydrostatic testing that were attributed to SCC, but no in-service failures have been attributed to SCC. Operator D considers that the hydrostatic testing program has demonstrated success in avoiding in-service failures due to SCC.

When a hydrostatic testing failure attributed to SCC has occurred in a valve section, that valve section is characterized as SCC Susceptible Site for purposes of retesting. The next downstream valve section may also be included in the test program. Valve section characterized as SCC Susceptible Sites are scheduled for retesting, with the first interval being 3 years. If the re-test of a